BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2023-388-E

In the Matter of	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Carolinas, LLC	)	**MORGAN BEVERIDGE**
For Authority to Adjust and Increase its Electric	)	**FOR DUKE ENERGY**
Rates and Charges	)	**CAROLINAS, LLC**
	)	

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Morgan Beveridge, and my business address is 525 South Tryon Street, Charlotte, NC 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as Manager of Rates and Regulatory Strategy for Duke Energy Carolinas, LLC ("DEC"). DEBS is a service company subsidiary to Duke Energy Corporation ("Duke Energy") that provides services to Duke Energy and its subsidiaries, including DEC and its affiliated utility operating companies.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGER OF RATES AND REGULATORY STRATEGY?

A. I am responsible for rate administration, rate design and pricing for DEC.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Chemical Engineering from University of Florida in 2013. I joined Duke Energy in the same year and worked in various engineering roles over the next eight years. My primary responsibilities were process engineering and program management, and my experience spanned environmental controls and compliance, fuel strategy, regulatory strategy and resource planning. In 2019, I transitioned from Senior Engineer to Senior Analyst for Distributed Energy Planning and Forecasting where I specialized in solar and wind generation, energy storage and electric

vehicles. In 2020, I joined the Rate Design and Regulatory Solutions team, where I now work as Manager of Rates and Regulatory Strategy for DEC.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA (THE "COMMISSION")?

A. No. I have not. However, I recently testified before the North Carolina Utilities Commission in Docket No. E-7, Sub 1276 for the 2023 DEC-NC rate case.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony focuses on the rates DEC proposes in this proceeding. Specifically, my testimony supports those rates as reflecting appropriate rate making principles, resulting in an equitable basis for recovery of DEC's revenue requirements across and within its various customer classes and rate schedules. I also describe new customer-centric and innovative rate design and pricing changes to address emerging trends impacting South Carolina today and to assist in harmonizing the rate designs and structures between DEC and Duke Energy Progress, LLC ("DEP"). My testimony also: (1) describes DEC's methodology for designing new rate structures and updating time-of-use ("TOU") periods; (2) describes the changes to DEC's retail electric rate schedules; (3) quantifies the effect of these proposed changes on DEC's South Carolina retail electric customers; (4) discusses how DEC proposes to implement the tariffs approved by the Commission in this proceeding; and (5) describes other requested changes to DEC's tariffs.

Q. PLEASE DESCRIBE THE EXHIBITS ATTACHED TO YOUR TESTIMONY.

A. The exhibits to my testimony are as follows:

- Beveridge Exhibit 1 provides the South Carolina Retail Electric Rate Schedules and Service Regulations DEC proposes to be effective for service rendered on and after August 1, 2024, as required by S.C. Code Ann. Reg. 103-823(e). This exhibit is the same as Exhibit B to the DEC's Application in this docket;
- Beveridge Exhibit 2a is a rate comparison that sets forth the South Carolina retail rate design revenues under DEC's present and proposed rate schedules with the proposed change in the Excess Deferred Income Tax Rider EDIT-1;
- Beveridge Exhibit 2b is a rate comparison that sets forth the South Carolina retail rate design revenues under DEC's present and proposed rate schedules without the proposed change in the Excess Deferred Income Tax Rider EDIT-1;
- Beveridge Exhibit 3 shows the rate derivation and description of rate and tariff changes;
- Beveridge Exhibit 4 provides a comparison of rate of return by rate class and illustrates the total revenue requirement by class for which rates have been designed;
- Beveridge Exhibit 5 illustrates the comparison of present and proposed rates by major rate schedule;

- Beveridge Exhibit 6 illustrates the Basic Customer Charges (previously called Basic Facilities Charges) for the major customer classes;
- Beveridge Exhibit 7 illustrates the derivation of the Excess Deferred Income Tax Rider EDIT-1 proposed changes;
- Beveridge Exhibit 8 is a chart showing a visual comparison between DEC's current and proposed TOU periods;
- Beveridge Exhibit 9 is a figure showing TOU period alignment with recent marginal energy costs (average from 2020-2022);
- Beveridge Exhibits 10, 11, and 12 are figures showing TOU period alignment with the Cost Duration Model output for the years 2021, 2026 and 2030, respectively; and
- Beveridge Exhibit 13 is a figure showing TOU period alignment with 2027 Loss of Load Expectation times.

Q. WERE BEVERIDGE EXHIBITS 1 THROUGH 13 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. WERE THE TARIFFS FILED AS EXHIBITS TO THE APPLICATION PREPARED BY YOU OR AT YOUR DIRECTION?

A. Yes. Application Exhibit A presents DEC's current tariffs that are requested to be revised in this proceeding. Application Exhibit B provides the proposed tariffs and reflects the changes that are described in detail in my testimony. Application Exhibit C presents DEC's current tariffs highlighting all proposed

changes to rates and terms. These exhibits were prepared at my direction and reflect the changes being sought in this proceeding.

Q. PLEASE PROVIDE AN OVERVIEW OF HOW THE RATE DESIGNS PROPOSED IN THIS DOCKET ADDRESS THE MORE SIGNIFICANT EMERGING ENERGY TRENDS IMPACTING SOUTH CAROLINA.

A. South Carolina, like many other states, is facing several broad energy trends that create both challenges and opportunities. As I discuss in greater detail in my testimony, rate design and pricing must adapt to reflect the impacts such shifts are driving in resource planning and system management. For example, anticipated growth of technology with unique or controllable load characteristics, such as electric vehicles ("EVs"), present opportunities for customers and must be considered in modern rate designs. DEC is proposing rate design changes, similar to those recently approved by the Commission and implemented by DEP, to accommodate and anticipate these trends, while maintaining or improving alignment between cost of service and proposed target revenues for each rate class.

To develop an informed vision and direction for these pricing and rate designs options, DEC participated in the year-long Comprehensive Rate Design Study ("CRDS") with external stakeholders across the Carolinas. The study process included broad participation from very engaged organizations, relied upon stakeholder feedback and presentations to guide and prioritize the study scope, and yielded possibilities for constructive rate design changes that balance priorities and desires of the participating organizations.

As I will discuss later in my testimony, DEC is making several changes to directly incorporate requests and input from stakeholders. These changes reflect the learnings from that collaborative process, as well as DEC's modernized rate design philosophy. Overall, the rates have been revised to produce the target class and total revenue requirements being sought in this proceeding. Additionally, DEC is also proposing a series of rate design changes to protect customers from cross-subsidizations, send price signals that encourage system beneficial consumption, and generally modernize DEC's pricing structure.

Most significantly, DEC is proposing updated and aligned TOU periods across DEC's tariffs that contain time-differentiated pricing for both residential and non-residential customers. Consistent with the time period updates, DEC must necessarily modify demand charge structures to align with the new periods. Together, these changes improve price and cost-causation alignment, allow for simplification elsewhere in the rate designs, and offer greater opportunity for load management activities to control customers' energy costs and create benefits for the broader system.

II. SUPPORT OF PRO FORMA ADJUSTMENTS

Q. DID YOU PROVIDE ANY INFORMATION USED IN CONNECTION WITH THE PRO FORMA ADJUSTMENTS MADE TO THE TEST YEAR IN THIS PROCEEDING?

A. Yes. I provided the annualized revenue under current rates, which was used in connection with the pro forma adjustments. This revenue is exclusive of

revenues derived from the (i) Demand Side Management ("DSM") and Energy Efficiency ("EE") Rider, (ii) Fixed Monthly Leaf 50C Charge (Distributed Energy Resource Program or "DERP" Charge) and (iii) Excess Deferred Income Tax ("EDIT") Rider EDIT-1. This revenue was used to establish annual revenues in the cost of service study. This type of adjustment is required to establish a level of revenue that would be received assuming that annual rate adjustments in effect on and after the date of DEC's Application had applied for all 12 months of the year ended December 31, 2022 ("Test Year").

Q. ARE YOU SPONSORING A PRO FORMA ADJUSTMENT BASED UPON THE REQUESTED RATES APPLICABLE FOR MISCELLANEOUS REVENUES?

A. Yes. Based upon the proposed rates contained in the Service Regulations and in the Manually Read Meter ("MRM") Rider, a pro forma adjustment decreasing miscellaneous revenues by $1.0 million should be included in cost of service. The changes in these rates are addressed later in my testimony.

III. RETAIL ELECTRIC RATE SCHEDULES AND RIDERS

A. Rate Design Approach

Q. HOW DID DEC DESIGN THE PROPOSED RATES IN THIS CASE?

A. I used the cost of service information prepared by DEC and supported by Witness Janice Hager as a major component for the rate design. As Witness Hager describes in her testimony, the cost of service study allocates costs to the jurisdictions and various rate classes and separates the customer, demand and energy components of those costs. I also reviewed and considered the rates of

return across the customer classes derived from the cost of service study. With this information, the target total proposed change in revenue requirement was determined for each rate class. Then, the rate schedules within each rate class were designed to sum to the total proposed change in revenue target for that respective rate class.

Q. WHAT OTHER INFORMATION DID DEC USE TO INFORM AND EVALUATE ITS RATE DESIGNS?

A. I reviewed DEC's Advanced Metering Infrastructure ("AMI" or "Smart Meter") data to examine customers' usage characteristics. I leveraged this data to determine relationships between energy and demand, both on a coincident peak and non-coincident peak basis that might prove pertinent to the design of DEC's rates—including the development of new TOU periods. Additionally, many aspects of DEC's proposed rate designs in this case are informed by the recommendations and work product arising from the CRDS. DEC participated in the CRDS with external stakeholders to develop an informed vision and direction for DEC's future pricing and rate design options.

Q. WHAT ARE DEC'S RATE DESIGN OBJECTIVES FOR THE RATES PROPOSED IN THIS PROCEEDING?

A. As discussed by DEC Witness Michael Callahan, DEC is requesting a rate increase to recover its costs of providing safe and reliable electric service and to maintain a strong financial position as it remains in a period requiring major capital expenditures. DEC's projected revenue from present rates, as discussed by DEC Witness LaWanda Jiggetts, is below its cost of service. Therefore, an

objective of DEC's proposed rate design is to achieve the necessary increase in rates to collect the total revenue requirement. In doing so, DEC seeks to further align the cost to serve customers within our residential, general service, industrial and lighting rate schedules by designing rates that reflect the costs a customer causes DEC to incur. Another objective is to provide customers with modern rate options that provide opportunities for bill savings and enable adoption of new technologies that can benefit the grid and the environment.

Q. DID DEC CONSIDER RECOGNIZED RATE DESIGN PRINCIPLES AS PART OF ITS RATE DESIGN PROCESS?

A. Traditional rate design principles including gradualism, sending relevant price signals, customer acceptance, administrability, and avoiding undue discrimination among customers were central to DEC's process. Current rates and their structure, equitable pricing structures, simplicity of rate design, administrative complexity, and rate and revenue stability were also considered when establishing DEC's proposed rates. DEC took a granular analytical approach to apply functionalized costs within rate designs and to evaluate revenue impacts for individual customers and customer classes. DEC also measured how rates reflect both embedded and marginal costs and considered adoption of emerging technologies such as EVs, energy storage and solar generation, for both customer-sited and utility-scale applications.

Q. WHAT ARE DEC'S SERVICE CLASSIFICATIONS AND MAJOR RETAIL ELECTRIC RATE SCHEDULES?

A. DEC's retail customers are separated into five service classifications: Residential, General Service, Industrial, Lighting, and Greenwood. For the purposes of this proceeding, Optional Power Service Time-of-Use Schedule OPT and Multiple Premises Service (Pilot) Schedule MP, which include both General Service and Industrial customers, are categorized as a separate "OPT" class. The Greenwood class includes rate schedules previously served under the Greenwood County Electric Power Commission Rural Electric System and, with the exception of Greenwood Schedule SL as discussed later in my testimony, is generally not included in, or impacted by, this proceeding.

DEC's major retail electric rate schedules include Residential Schedule RS and RE; General Service Schedules SGS and LGS; Industrial Schedule I; Schedule OPT; and Lighting Schedules OL and PL. Together, these rate schedules comprise a substantial portion of DEC's retail electric revenue requirement.

Q. PLEASE EXPLAIN HOW THE REVENUES PRODUCED UNDER PRESENT RATES COMPARE TO THE REVENUES THAT WOULD BE PRODUCED BY THE PROPOSED RATES.

A. As required by S.C. Code Ann. Reg. 103-823(e), Beveridge Exhibits 2a and 2b set forth a comparison of the revenue produced by the present schedules for the Test Year with the revenue that would be produced under the proposed schedules, with and without the change in the EDIT-1 rider, respectively. For

comparison, both the present and proposed revenues reflect the base fuel and fuel-related costs component discussed by Witness Jiggetts in her testimony. The revenues produced by the schedules shown in columns (B) and (C) were calculated by using the South Carolina retail sales for the Test Year. The exhibits show the amount of additional revenue produced by the proposed rates and the percentage increase for each rate schedule. Incremental revenues from Hourly Pricing Schedule HP are excluded from the baseline rate schedules and shown separately on Exhibits 2a and 2b due to the differences of marginal cost versus embedded cost rate making. Historically, any additional revenues allocated to this rate were borne by the respective baseline rates through rate design. The cost of service treatment formalizes this approach.

Q. HOW DOES DEC PROPOSE TO ALLOCATE THE REVENUE INCREASE AMONG THE RATE CLASSES?

A. The base rate increase has been allocated to the rate classes by rate base amounts. This allocation methodology distributes the increase equitably to the classes while maintaining each class's deficiency or surplus contribution to return. As shown in Beveridge Exhibit 4, DEC is also recommending a variance reduction of 10 percent to reduce interclass cross-subsidization by better aligning each rate class to the average rate of return. DEC remains committed to monitoring cross-subsidization and making improvements to ensure its rates are fair across the classes of customers served.

Q. DID DEC CONSIDER THE REVENUE IMPACTS OF RATE MIGRATION WHEN DESIGNING RATES?

A. Yes. DEC analyzed rate migration in the rate design process. Rate migration occurs when customers migrate from their current tariff to another tariff to save money. DEC is recommending a migration adjustment for small and medium customers (under 1,000 kilowatt ("kW") demand) who would save 10 percent or more annually and for large customers (1,000 kW and above) who would save 5 percent or more annually. Customers who are above the savings threshold used in the DEC's analysis are likely to switch, particularly due to customers now having access to previously unavailable rate comparison information through the rate comparison tool. Some customers below the threshold may also switch but were not included in the DEC's proposed adjustment to remain conservative. The proposed migration adjustment amounts are approximately $5.8 million for the Residential class, $0.8 million for the General Service class, and $5.4 million for the OPT class. Beveridge Exhibit 4 displays the requested migration adjustment amounts. These migration adjustments are supported by the introduction of new tariffs, the redesign of tariffs to better align with system costs, and the ability of DEC's new billing system to perform rate comparisons to help customers identify the lowest-cost rate.

Q. WHAT IS THE BENEFIT OF INCLUDING A MIGRATION ADJUSTMENT?

A. The proposed rate migration adjustment is designed to account for revenue erosion associated with customers switching from one rate to another to save money. The requested migration adjustment ensures that DEC recovers the full amount of the revenue requirement, which in turn protects other classes from absorbing these costs in future rate cases through interclass subsidies.

Q. HOW DID DEC CONSIDER THE RESULTS OF A UNIT COST STUDY IN DESIGNING THE PROPOSED RATES?

A. The unit cost study from the cost of service study provides customer, demand and energy related unit costs that are important in establishing cost-based rates. Setting rates that are aligned with unit cost minimizes interclass cross-subsidization and signals to customers the true cost impact of their usage. DEC's proposed rate designs improve alignment with unit cost by shifting revenue from energy to demand where applicable and by increasing the Basic Customer Charge for non-residential rate schedules.

Q. HOW DID DEC CONSIDER EQUITABLE PRICING STRUCTURES IN DESIGNING THE PROPOSED RATES?

A. Equitable pricing structures, or rate parity, involves adjusting rate schedules and riders to achieve a uniform return. The rate adjustments proposed by DEC in this proceeding are intended to move all rate schedules closer to a more equitable pricing structure. DEC is seeking to achieve an equitable pricing

structure in steps in recognition that the imbalance in class and rate schedule returns did not occur overnight and should not be corrected overnight.

Q. IS DEC PROPOSING ANY NEW RATE DESIGNS IN THIS PROCEEDING?

A. Yes. DEC is proposing two new TOU rate schedules with critical peak pricing ("CPP") for the Residential class: Schedules RSTC and RETC. Schedule RSTC would be available to all residential customers, and Schedule RETC would be available to residential customers that meet the electric water heating and space conditioning requirements of Schedule RE.

Q. HOW WILL THE PROPOSED REVENUE INCREASE IMPACT THE RESPECTIVE REVENUE CLASSES?

A. The proposed revenue increase is distributed among customer rate classes by increasing the respective rate schedules as shown in Beveridge Exhibit 4. Beveridge Exhibits 2a and 2b illustrate the rate class changes and incorporate the effects of migrations and other riders. Beveridge Exhibit 5 provides detail regarding the impacts of the proposed revenue increase on the major rate schedules.

B. Rate Design Modernization

Q. PLEASE SUMMARIZE THE MORE SIGNIFICANT EMERGING ENERGY TRENDS IMPACTING SOUTH CAROLINA TODAY THAT CALL FOR RATE DESIGN CHANGES OR REVISIONS.

A. Several DEC witnesses in this proceeding discuss the fact that South Carolina, like many other states, is facing several broad energy trends that create both

challenges and opportunities. Rate design and pricing must adapt to reflect the impacts such shifts are driving in resource planning and system management. For example, meter technology advances enable more sophisticated rate designs that can provide both improved price signals and improved alignment between customer charges and usage behaviors impacting cost of service. Similarly, end-use technology advancements are enabling monitoring and control of energy loads such that customers can act upon more sophisticated price signals with load management. The expansion of solar generation in DEC's service territory, which is expected to continue, is reshaping net peak demand. Finally, anticipated growth of technology with unique or controllable load characteristics, such as EVs, present opportunities for customers and must be considered in modern rate designs. DEC is proposing rate design changes to accommodate and anticipate these trends, while maintaining or improving alignment between cost of service and proposed target revenues for each rate class.

Q. PLEASE DESCRIBE THE PROCESS DEC USED TO DEVELOP THESE NEW RATE DESIGNS.

A. DEC participated in the year-long CRDS with external stakeholders across the Carolinas to develop an informed vision and direction for DEC's future pricing and rate design options. The study process included broad participation from very engaged organizations, relied upon stakeholder feedback and presentations to guide and prioritize the study scope, and yielded possibilities for constructive rate design changes that balance priorities and desires of the participating

organizations. More than 50 organizations participated, including commercial and industrial customers, EV companies and advocates, environmental advocates, government agencies, public advocates, renewable/distributed energy resource companies, and legal/consulting companies.

Q. PLEASE PROVIDE AN OVERVIEW OF THE SCOPE OF THE CRDS AND HOW THE CRDS IMPACTS THE RATE DESIGN IN THIS DOCKET.

A. Importantly, the scope included shifting grid dynamics, incorporation of distributed energy technologies, and recognition of varying customer expectations across all major tariffs and riders. Quarterly updates on the study and the associated roadmap were filed informationally with the Commission in ND-2021-12-E. As I will discuss later in my testimony, DEC is making several rate changes to directly incorporate requests and input from stakeholders during the CRDS, and DEC's modernized rate design philosophy reflects the learnings from that collaborative process.

Q. PLEASE SUMMARIZE THE MORE SIGNIFICANT RATE DESIGN CHANGES OR REVISIONS DEC IS PROPOSING TO MAKE TO ITS TARIFFS IN THIS PROCEEDING.

A. As with any rate case, the rates have been revised to produce the target class and total revenue requirements being sought in this proceeding. Additionally, DEC is also proposing a series of rate design changes to protect customers from cross-subsidizations, send price signals that encourage system beneficial consumption, and generally modernize DEC's pricing structure.

Most significantly, DEC is proposing updated and aligned TOU periods across DEC's tariffs that contain time-differentiated pricing for both residential and non-residential customers. Consistent with the time period updates, DEC must necessarily modify demand charge structures to align with the new periods. Together, these changes improve price and cost-causation alignment, allow for simplification elsewhere in the rate designs, and offer greater opportunity for load management activities to control customers' energy costs and create benefits for the broader system.

DEC is also proposing new residential TOU-CPP rates (Schedules RSTC and RETC) and a redesigned hourly pricing rate (Schedule HP) to expand rate options for customers.

I will describe the basis and rationale for the new TOU periods and demand charge structures, as well as the benefits of the new and redesigned tariffs mentioned above.

C. Time of Use Periods and Rate Design

Q. WHAT CHANGES ARE YOU PROPOSING TO TOU PERIODS?

A. DEC proposes to refresh all TOU periods for open tariffs (except Schedule R-STOU, as explained below) as follows:

- On-peak, Summer – 6:00 PM to 9:00 PM
- On-peak, Non-summer – 6:00 AM to 9:00 AM
    - On-peak periods do not apply to weekends and designated holidays
- Discount, Summer – 1:00 AM to 6:00 AM

- Discount, Non-summer – 1:00 AM to 3:00 AM and 11:00 AM to 4:00 PM
- Off-peak – All hours not designated as On-peak or Discount
- Summer months comprise May through September
- Non-summer months comprise October through April

A chart showing a visual comparison of the existing TOU time periods and DEC's proposed TOU time periods is attached to my testimony as Beveridge Exhibit 8.

Q. WHAT IS THE BASIS FOR THE PROPOSED TOU CHANGES?

A. Broadly, TOU energy rates can include a variety of pricing and design options, but generally all TOU energy rates seek to align price signals to the cost differences that exist across time (days, seasons, hours) for the electricity grid. Grid operations require that supply match demand at any given point in time; thus, supply resources are called upon based on the level of system demand, which can vary greatly across days and seasons. Increasingly, intermittent and non-dispatchable supply resources (e.g., solar) are changing the supply/demand relationship, calling for changes in operational capabilities for the other supply resources but also for demand. Proper rate design seeks not only to recover the costs of providing service to customers based on their use of the system, but also to provide price signals so that customers who can respond to price signals can do so in an informed manner. TOU pricing with properly defined periods is necessary to ensure proper signaling. DEC's existing TOU periods, established decades ago, are no longer appropriate and increasingly do not align

with DEC's current and anticipated system needs. Furthermore, the desire for this refresh of TOU periods emanates from the evolving needs of the electric system and its ability to provide superior price signals, which can enable cost effective customer adoption of new technologies, such as smart energy management devices, energy storage and EVs.

Q. PLEASE EXPLAIN DEC'S APPROACH TO DESIGNING THE NEW TOU PERIODS.

A. DEC took a forward-looking approach in designing the new TOU periods discussed above, considering both current conditions and expected system evolution through 2030. Multiple perspectives and goals were considered in crafting periods that: (1) better reflect cost causation and the growing impact of solar generation; (2) accommodate changing consumption patterns caused by distributed energy technologies such as EV charging, energy storage, rooftop solar and other distributed energy technologies; and (3) facilitate customer modification of energy consumption patterns to create bill savings.

Q. HOW DID DEC DETERMINE THE DURATION AND PRICING FOR THE NEW TOU PERIODS?

A. DEC analyzed projected load patterns and costs to develop refreshed TOU periods. Historical and forecasted costs were analyzed through five different lenses: gross load, net load after utility-scale solar, retail load, marginal energy cost, and loss of load expectation ("LOLE"). Gross load, net load, retail load, and marginal energy cost were examined using DEC's Cost Duration Model ("CDM"), which was also used to set the prices for Residential Service, Solar

Time-of-Use Schedule R-STOU, approved in 2021. The revised TOU periods that DEC is proposing in this case were derived directly from observations of the CDM, which can be seen in Beveridge Exhibits 9-13.

Q. CAN YOU PLEASE EXPLAIN THE CDM?

A. The CDM provides improved linkage between recovery of system costs (e.g., tariff pricing) and the time periods during which system assets are being utilized. For all three major utility functions (generation, transmission and distribution), some assets are only used to meet demand during a small number of peak hours, while other assets are used for all or nearly all hours. The CDM allocates costs for assets across all three functions based on anticipated utilization. Costs for assets used during all hours are assigned accordingly, while cost for assets used only during peaking hours are concentrated in those hours (e.g., early winter morning hours).

As generation, transmission and distribution demands are not perfectly coincident, costs for each function were distributed independently, using specific load duration curves. Generation costs were allocated using net peak load duration (gross load net of utility-scale solar); transmission capacity costs were allocated using gross system load duration; and distribution capacity costs were allocated using a distribution load duration curve for the customer class for which rates were being designed (e.g., residential load duration curve for residential customers). The following five steps outline the cost allocation process across all hours, for each function using its respective load duration curve.

Step 1: Capacity costs were divided by the peak load of each load duration curve to find a unit cost per megawatt ("MW") of capacity.

Step 2: The incremental load in each hour was calculated by taking the difference in load between that hour and the hour with the next highest load. For the lowest load hour of the year, the load in that hour is used. Note that the sum of all these incremental load amounts is necessarily equal to the peak load.

Step 3: For each hour, the incremental load was shared evenly between the hour in question and all hours of the year that have a higher load than the hour in question. The incremental load at the highest load hour was not shared as there are no higher load hours. The incremental load at the second highest hour was shared evenly between the top two hours, and so forth.

Step 4: Next, load allocated to each hour was totaled. The highest load hour has a share of load for all hours of the year, the second highest load hour has a share of load for all hours of the year except the highest hour, and so forth.

Step 5: Finally, the load allocated to each hour in Step 4 was multiplied by the unit cost calculated in Step 1 to calculate the total cost of each hour. This can in turn be divided by the billing load in that hour to calculate the unit cost of each hour.

Combining the results of the CDM for each customer class with hourly energy costs provides the variable cost of serving the respective customer class

in each hour of the year. In combination with the TOU periods described above, prices for each TOU period can be established to recover those costs for each respective period. Prices may be slightly modified to ensure estimated revenue is as close as possible to, but not exceeding, the revenue requirement.

Q. WHAT WERE THE RESULTS OF THE CDM?

A. Beveridge Exhibits 9-13 show that the CDM is in alignment with historical marginal energy costs. Because capacity constrained hours will also have high marginal energy costs (when the utility is at the high end of its economic dispatch curve), this shows good alignment on capacity costs as well. The impact of additional solar energy added between 2021 and 2030 is clearly reflected in the summer afternoon peak being pushed further back into hours with less sunlight. For the same reason, the non-summer mid-day period exhibits even lower cost, as these times of high solar generation and relatively low load lead to "duck-curve" situations where solar curtailment could become necessary. As a result, DEC is proposing a discount pricing period during such hours to better reflect lower cost of service. Also, the April load shape more closely aligns with the non-summer period than the summer period. Finally, the LOLE chart shows that the highest capacity cost hours are in winter mornings and relatively little of the LOLE is not covered by on-peak hours, underscoring the appropriateness of the proposed periods.

Q. PLEASE EXPLAIN THE CHALLENGES INHERENT IN THE EXISTING TOU PERIODS AND HOW THE UPDATED TOU PERIODS ADDRESS THOSE CHALLENGES.

A. As seen in Beveridge Exhibit 8, DEC's historical TOU periods vary significantly and do not reflect current system costs and operational realities reflected in the CDM analysis. Continued use of the existing periods would result in customers receiving inappropriate price signals discouraging consumption when the system in fact has an abundance of solar energy, thus increasing the likelihood of solar curtailment. Conversely, the historic periods contain off-peak hours that are increasingly becoming times of system peaks, notably late afternoon hours during the summer. Thus, customer responsiveness to the existing periods and price signals may exacerbate the evening summer peak and increase costs to all customers.

Additionally, the historical on-peak periods present challenges for customers seeking to respond to prices, whether through advanced energy management controls or with distributed energy technologies such as storage. Beveridge Exhibit 8 shows that some existing on-peak periods are up to eight hours in length, compared to the three-hour window for the proposed on-peak periods that reflect current system realities. The new, shorter window creates more opportunities for customers to manage usage patterns or utilize distributed energy storage to reduce their electricity bills.

The modernized periods provide a consistent discount period for owners with flexible loads (e.g., residential and fleet EVs), during the overnight hours

from 1:00 AM to 3:00 AM (for both summer and non-summer) and extending to 6:00 AM in the summer. The discount periods provide an important foundation to all customers with such flexible loads.

DEC proposes these changes based on anticipated continuation of load dynamics as a result of solar proliferation. Importantly, DEC considered rate stability (including TOU period definitions) in developing the proposed times with the goal of avoiding further changes for several years. Frequent changes to TOU periods are inadvisable and potentially burdensome as customers use price periods to evaluate energy investments and program load management devices (e.g., thermostats, EV chargers). Accordingly, DEC has relied upon net peak forecasts through 2030 for the development of the new TOU periods. DEC proposes using these TOU periods for all TOU rates, except for Schedules R-STOU, PG and MP for the reasons described later in my testimony.

Q. WHICH RATE AND RIDER TARIFFS ARE IMPACTED BY DEC'S PROPOSED UPDATES TO TOU PERIODS?

A. The impacted tariffs are residential Schedule RT and non-residential Schedule OPT. Additionally, the new residential TOU-CPP rates proposed in this case (Schedules RSTC and RETC) are based on the updated TOU periods.

Q. WHY IS DEC NOT PLANNING TO UPDATE THE TOU PERIODS IN SCHEDULE R-STOU IN THIS PROCEEDING?

A. DEC's solar TOU-CPP rate, Schedule R-STOU, was previously approved by the Commission in Docket No. 2020-264-E and became effective January 1, 2022. The rate is restricted to solar customers on Residential Solar Choice

Rider RSC and includes solar-specific features such as a monthly non-bypassable charge and grid access fee. The TOU periods in Schedule R-STOU generally align with the periods proposed in this case and were designed using a similar approach including a CDM. Due to the recent approval of these TOU periods and the terms of the Memorandum of Understanding approved by the Commission in that docket, DEC is not proposing any structural changes to R-STOU in this rate proceeding.

D. Residential Service

Q. PLEASE DESCRIBE DEC'S RESIDENTIAL SCHEDULES.

A. Schedule RS is the basic residential service rate schedule available to all residential customers. Schedule RE is available to qualifying residential customers with electric water heating and space conditioning. Schedule ES mirrors the rate structure of Schedules RS and RE and provides a five percent discount on energy charges for customers that meet the qualifications of the Energy Star program. Schedule RB is a legacy rate schedule, available to customers that meet certain thermal conditioning and equipment standards, that has been closed to new customers since 1991. Schedule RT is a TOU rate with a demand charge. Schedule R-STOU is a TOU-CPP rate available to net metering customers on Residential Solar Choice Rider RSC.

Q. IS DEC PROPOSING TO INCREASE THE RESIDENTIAL BASIC CUSTOMER CHARGE IN THIS CASE?

A. No. While the unit cost study justifies an increase to the monthly residential Basic Customer Charge ("BCC") based on customer-related costs, DEC is not

proposing to raise the residential BCC in this proceeding based on significant feedback from stakeholders in prior rate proceedings. The Basic Customer Charges for the major rate schedules are provided in Beveridge Exhibit 6.

Q. IS DEC PROPOSING ANY CHANGES TO ITS RESIDENTIAL RATE DESIGNS?

A. Yes. DEC is proposing to redesign its residential TOU-demand Schedule RT based on new TOU periods and a new demand charge structure. DEC is also proposing to close legacy Schedule RB and transition customers to alternate available rates.

Q. PLEASE DESCRIBE THE PROPOSED REDESIGN OF SCHEDULE RT.

A. DEC proposes to redesign Schedule RT based upon the new TOU periods discussed above. In addition, DEC is proposing that the demand structure for RT be modified to include two parts: (1) a demand charge component for the highest on-peak demand during the billing period; and (2) a demand charge component for the highest demand regardless of time period during the billing period. Such a structure is important to ensure recovery of fixed distribution costs, for example, for customers who may use batteries to avoid peak demand charges. Finally, DEC is proposing to eliminate the seasonality in rates for demand charges on Schedule RT. DEC believes such change is appropriate given the transition to the 12 Coincident Peak cost allocation methodology discussed in Witness Hager's testimony. Additionally, the modernized TOU periods serve to provide adequate pricing signals based on seasonal system

loads as the on-peak, off-peak and discount pricing periods are differentiated by season.

Q. WHY IS DEC REQUESTING TO CLOSE LEGACY SCHEDULE RB?

A. Schedule RB has been closed to new customers since 1991. It has an identical rate structure as standard Schedule RS but with higher prices. Load profiles and cost of service for Schedule RB customers are not materially distinct from Schedules RS and RE, and the small number of customers make it generally inefficient for rate and tariff administration.

Q. WILL CLOSING SCHEDULE RB RESULT IN INCREASED BILLS FOR ANY CUSTOMERS?

A. No. Standard Schedule RS has an identical structure and lower prices compared to Schedule RB, so no customers will see rate increases as a result of closing Schedule RB.

Q. IF APPROVED, HOW WILL DEC TRANSITION CUSTOMERS CURRENTLY ON SCHEDULE RB?

A. If approved, DEC plans to notify Schedule RB customers of the transition, through available communication channels including email, as soon as practicable following an order from the Commission. DEC plans to transition all Schedule RB customers to Schedule RS in the months following the effective date of compliance rates but no later than December 31, 2024. Prices for Schedule RB would be set equal to Schedule RS for compliance rates to ensure that all Schedule RB customers receive equal pricing treatment irrespective of transition timing. Schedule RB customers would have the

opportunity to request a rate change to a different eligible residential rate schedule other than Schedule RS through normal channels. Customers that are automatically transitioned to Schedule RS upon closing of Schedule RB would be exempt from the standard 12-month contract period, such that they could request transition to a different rate schedule at any time.

Q. IS DEC SEEKING A MIGRATION ADJUSTMENT RELATED TO CLOSING SCHEDULE RB?

A. No. Proposed prices for Schedule RB are set equal to Schedule RS, so no migration adjustment is needed.

Q. IS DEC PROPOSING ANY NEW RESIDENTIAL RATE SCHEDULES?

A. Yes. DEC is proposing two new TOU-CPP rate schedules for the Residential class: Schedules RSTC and RETC. Schedule RSTC would be available to all residential customers, and Schedule RETC would be available to residential customers that meet the electric water heating and space conditioning requirements of Schedule RE. These new rate structures will allow customers who do not have distributed solar but do have other load management devices (e.g., smart thermostats, EV chargers) greater opportunity to reduce costs through load shifting and avoiding on-peak periods. The CPP element of these rates allows DEC to call up to 20 critical peak events per year to encourage load reduction during times of grid constraints and thereby creating opportunities for customers to save for such reduction activities.

Q. DOES DEC PROPOSE ANY OTHER CHANGES TO THE RESIDENTIAL RATE SCHEDULES?

A. Yes. DEC proposes to broaden the applicability of residential rates to include detached garages, barns, or other structures that are at the same service address as a separate, primary residential account and that are not used primarily for business purposes. The current policy is to serve detached garages, barns, or other structures on a general service rate schedule if the structure does not provide for living, sleeping, eating, cooking and sanitation.

Q. WHY IS DEC PROPOSING TO EXPAND THE APPLICABILITY OF RESIDENTIAL RATES TO INCLUDE STRUCTURES AT THE SAME SERVICE ADDRESS AS THE RESIDENTIAL ACCOUNT?

A. We are proposing this change in response to feedback from our customers on our current policy. In general, customers question why they are billed on a "commercial rate" for what they believe to be residential usage. Based on feedback from customers and the current language in the tariff, DEC believes it is appropriate to include detached garages, barns and other structures on residential rates as long as the detached structures are located on the same premise as the residential dwelling unit and the structures are primarily used for residential purposes (as opposed to business purposes). DEC has proposed clarifying language in its residential rate schedules.

Q. IF THIS CHANGE IS APPROVED, WILL DEC ALLOW EXISTING CUSTOMERS TO MOVE FROM A GENERAL SERVICE SCHEDULE TO A RESIDENTIAL SCHEDULE FOR A DETACHED STRUCTURE THAT IS USED PRIMARILY FOR RESIDENTIAL PURPOSES?

A. Yes. As of the effective date of the approved change, DEC will allow customers to migrate from a general service rate schedule to a residential rate schedule for detached structures at the same premise as the residential account. Customers may contact DEC's call center to request the change. The rate change would be applicable prospectively.

Q. IS DEC REQUESTING A MIGRATION ADJUSTMENT TO RATES IN CONNECTION WITH THIS PROPOSED EXPANSION OF RESIDENTIAL AVAILABILITY?

A. No. DEC does not believe a migration adjustment is required for this rate, because the potential impact on revenue is insignificant due to the relatively small number and size of applicable structures.

Q. WHAT IS THE IMPACT OF THE PROPOSED RATES ON RESIDENTIAL CUSTOMERS' BILLS?

A. Beveridge Exhibit 5 illustrates the impact of the proposed increase on the major residential rate schedules.

E. General Service and Industrial

Q. PLEASE DESCRIBE DEC'S EXISTING GENERAL SERVICE AND INDUSTRIAL RATE SCHEDULES.

A. DEC's basic non-residential rate schedules are Small General Service ("SGS") Schedule SGS, Large General Service ("LGS") Schedule LGS and Industrial Service Schedule I. Schedule SGS is available to non-residential customers up to 75 kW; Schedule LGS is available to non-residential customers above 75 kW; and Schedule I is available to customers in the manufacturing sector. These rate schedules currently have non-TOU, tiered energy charges and a demand charge applicable above 30 kW.

DEC's non-residential TOU schedules are Optional Power Service Time-of-Use Schedule OPT; Multiple Premises Service (Pilot) Schedule MP; Parallel Generation Schedule PG; and Hourly Pricing for Incremental Load Schedule HP. The large majority of DEC's non-residential TOU customers are served under Schedule OPT. Schedule MP is a legacy pilot rate, closed to new customers since 2010, designed for businesses with two or more non-contiguous premises with a total contract demand of at least 5,000 kW. Schedule PG is available to customers operating power generating facilities in parallel with DEC and contains provisions for standby service. Schedule HP is an hourly pricing rate available to customers with a contract demand of at least 1,000 kW.

Lastly, DEC offers Building Construction Service Schedule BC for temporary service and Traffic Signal Service Schedule TS.

Q. PLEASE SUMMARIZE THE PROPOSED CHANGES TO THE GENERAL SERVICE AND INDUSTRIAL RATE SCHEDULES.

A. In addition to designing energy and demand rates to recover the proposed revenue increase, DEC is proposing the following:

- To increase the BCC for all General Service and Industrial rate schedules;
- To redesign the energy charge tiers for Schedule SGS;
- To redesign the TOU periods and demand charge structure for Schedule OPT;
- To redesign Schedule HP;
- To modify billing demand and minimum bill provisions;
- To modify standby service requirements;
- To update the industry classification system used to determine which customers qualify as Industrial; and
- To close Schedule PG to new participants.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE BCC FOR GENERAL SERVICE AND INDUSTRIAL RATE SCHEDULES.

A. DEC proposes to increase the BCC for all General Service and Industrial rate schedules to reflect the customer-related cost of serving these customers. As shown in Beveridge Exhibit 6, the unit cost study justifies an average monthly BCC of $48.90 for SGS schedules, $86.55 for LGS schedules, $88.83 for Industrial Schedule I, and $73.88 for OPT schedules. DEC proposes to increase all non-residential BCC rates at approximately the rate class revenue increase percentage, rounding to the nearest whole dollar where appropriate. The

proposed monthly BCC rates are $13.50 for Schedule SGS, $29.00 for Schedule LGS, $58.00 for Schedule PG, $27.00 for Schedule I, and $29.00 for Schedules OPT and MP. This incremental increase will move BCC rates in the direction of the customer unit costs while moderating the percentage increase in bills for customers with low monthly usage.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE ENERGY CHARGE UNDER SCHEDULE SGS.

A. DEC proposes to modify the energy charge structure of Schedule SGS with the goal of making the rate design more understandable and easier for customers to calculate, as informed by stakeholder discussions in the CRDS. The current energy charge structure comprises seven declining block tiers based on kilowatt-hours ("kWh") usage per max kW demand. This structure has the benefit of more accurately aligning price tiers with customer load factor, particularly when the range of customer demands is large. However, the availability requirements for Schedule SGS limit the customer base to a relatively narrow range of customer demands, i.e., less than 75 kW. Therefore, similar price objectives and outcomes can be achieved with a simpler declining block tier structure. DEC is proposing a three-tier declining block energy charge based on (1) first 3,000 kWh, (2) next 6,000 kWh and (3) over 9,000 kWh. This structure will achieve a similar correlation between average price and customer load factor, while meaningfully simplifying the description and calculation of the rate schedule.

DEC calculated illustrative "present equivalent" rates under the new tiers for comparison purposes. The ratios of the new price tiers were initially based on the ratios of existing corresponding price tiers. The ratios were then refined through unit cost analysis and bill impact analysis.

Q. HOW DID DEC DETERMINE THE PROPOSED RATES FOR SCHEDULES SGS, LGS AND I?

A. In designing energy and demand rates for Schedules SGS, LGS and I, DEC evaluated whether any shift in revenue between demand charges and energy charges was warranted and beneficial. DEC determined that a small shift in revenue from energy to demand was justified by the unit cost study and resulted in more equitable impacts across customers, for all three rate schedules. To implement this shift, demand rates were increased by one and a half times the percentage increase for the energy rates on the same schedule. Energy rates were increased by a fixed percentage to achieve the revenue requirement for each rate schedule.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO SCHEDULE OPT.

A. DEC is proposing to modify Schedule OPT to modernize the TOU periods and to update the demand charge structure to better reflect cost causation.

Q. WHAT CHANGES IS DEC PROPOSING TO THE DEMAND CHARGE STRUCTURE FOR SCHEDULE OPT?

A. As the TOU periods transition to a three-period structure, the non-residential demand structure must also change to maintain and improve upon the price

structure alignment with system costs. This will also provide actionable price signals to customers with flexible loads or enabled technology. Both objectives are important and must be held in balance when designing the ultimate rate structure. The three-part structure DEC is proposing is described below, including the costs each charge is conceptually designed to recover.

- Base Demand Charge: This charge is designed to recover distribution costs, which are the system costs in closest proximity to distribution-served customers. Such costs are not driven by overall system demand and are generally fixed throughout the year. Accordingly, the Base Demand Charge would apply to the customer's highest maximum demand across all periods over the last 12 months, or to 50 percent of the customer's contract demand, whichever is higher.
- Mid-Peak Demand Charge: This charge is designed to recover off-peak and discount allocation of production and transmission costs. This charge recovers capacity costs incurred to provide service during non-peak times. Accordingly, the Mid-Peak Demand Charge would apply to the customer's maximum demand during off-peak or on-peak periods (excludes discount periods).
- Peak Demand Charge: This charge is designed to recover peak allocation of production and transmission costs resulting from the customer's contribution to system demand during peak hours. Accordingly, the Peak Demand Charge would apply to the customer's measured on-peak demand.

The three-part demand structure improves price transparency and better aligns with cost causation based on both the size and timing of customer demands. Mid-Peak and Peak Demand Charges reflect the reality that demands at certain times impose more or less costs on the production and transmission components of the electric system. Similarly, the Base Demand Charge recovers system costs most directly caused by specific customers that do not vary based on the time of use (either by hour, by day, or by month). The Base Demand Charge helps reduce bill volatility for customers, and the Mid-Peak and Peak Charges offer opportunities for customers to manage demand and lower their bills. Relative recovery of costs between the three parts of this proposed demand charge structure were determined through the CDM to maintain cost causation linkage, as well as alignment with the methodologies used to set TOU energy charges. This new demand charge structure works in tandem and co-dependently with the updated TOU periods described above, which govern both energy and demand charges.

Q. IS DEC PROPOSING ANY OTHER CHANGES TO DEMAND CHARGES FOR SCHEDULE OPT?

A. Yes. During the CRDS, stakeholders requested information about the recovery of fixed costs through energy charges and asked whether such costs should be shifted more towards demand charges. Accordingly, DEC used interval data to evaluate the alignment of bills/pricing to cost causation. The analysis showed that shifting a portion of fixed cost recovery from energy charges to demand charges improved alignment to cost causation across a wide spectrum of

customer energy usage profiles. Importantly, a slight increase in demand charges, paired with a corresponding decrease in energy charges, could improve alignment in a meaningful way, with very little impact on bills for customers. As a result, DEC is proposing to shift revenue to demand by approximately three percent for Schedule OPT.

Q. IS DEC PROPOSING ANY CHANGES WITH RESPECT TO SEASONALITY FOR OPT CUSTOMERS?

A. Yes. Consistent with the change to Residential Schedule RT, DEC is proposing to eliminate the seasonality in demand charges on Schedule OPT.

Q. IS DEC PROPOSING STRUCTURAL CHANGES TO SCHEDULE MP, CONSISTENT WITH THE CHANGES TO SCHEDULE OPT?

A. No. DEC is proposing to maintain the current rate design for Schedule MP considering the small number of customers and that the rate is otherwise closed to new participation.

Q. IS DEC PROPOSING ANY CHANGES TO THE RATES UNDER SCHEDULE MP?

A. Yes. In addition to the proposed BCC, DEC is proposing rate increases for the energy and demand charges under Schedule MP, at an equal percentage, in order to achieve an overall rate increase equivalent to the OPT class.

Q. WHY IS DEC PROPOSING TO REDESIGN ITS HOURLY PRICING SCHEDULE HP?

A. DEC is proposing this redesign to better meet customer needs. During the CRDS, stakeholders expressed an interest in certain changes to yield a more

flexible marginal price rate with expanded availability, and this redesign achieves that.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO SCHEDULE HP.

A. The proposed Hourly Pricing rate will provide broader access for customers to marginal pricing. In addition, the new tariff will have features that encourage customers to be consistently price-responsive during times of grid constraints to retain that expanded access to marginal pricing. The mechanics of the redesigned rate are described in the revised tariff sheet included in Beveridge Exhibit 1. The tariff will remain available to all customers with load greater than 1,000 kW. DEC proposes to reestablish Customer Baseline Load ("CBL") every four years based on the customer's 12-month usage history, with modifications to reflect price-responsiveness during times of grid constraints. The CBL defines the level above which all kWh will be billed at hourly marginal energy prices. This new approach to reestablishing CBLs will restrict marginal prices to only four years for growing loads that are not consistently price-responsive, resulting in embedded cost recovery from such loads after the periodic CBL reestablishment. The CBL would be maintained or adjusted downwards, if mutually agreeable to the customer and DEC, to the extent the customer consistently reduces loads during times when grid constraints result in rationing charges within the hourly prices. DEC would allow for lower CBLs based on the average amount of reduction below the current CBL that the customer exhibited over a proceeding four-year period, in accordance with the Load Response Adjustment provision of the proposed tariff. DEC will include

a margin adder of $6 per megawatt-hour to account for day-ahead pricing uncertainty and provide some fixed cost recovery from the marginal energy purchases. Existing loads will be able to participate through establishment of an initial CBL and subsequent demonstration of price responsiveness, subject to the automatic CBL reestablishment process described above. The program design balances marginal pricing opportunities for incremental loads with assurance of embedded cost recovery from loads with limited price-responsiveness that drive future resource investment. As desired by stakeholders and discussed in the CRDS, the proposed rate allows for greater exposure to marginal prices, provided customers demonstrate price-responsiveness during grid events. Notably, DEC is proposing to eliminate the participation cap due to the durability and scalability of the new program design.

Q. HOW WILL THE REDESIGN OF SCHEDULE HP IMPACT EXISTING CUSTOMERS SERVED ON THE RATE?

A. Pricing changes will be effective for existing customers, but the requirement for automatic CBL reestablishment every four years will not apply unless and until the customer requests an update of their CBL for any reason. This grandfathering provision is specified in the proposed Schedule HP tariff.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO BILLING DEMAND AND MINIMUM BILL PROVISIONS.

A. DEC is requesting to modify the Determination of Billing Demand provisions under Schedule OPT based on the proposed three-part demand charge structure.

In concert, DEC is requesting to eliminate the Minimum Bill provision of Schedule OPT. DEC believes that the proposed rate design offers adequate provision for minimum bills, in large part due to the Base Demand Charge which applies to the higher of the maximum demand during the previous 12 billing months, or 50 percent of contract demand. This approach balances cost of service considerations while maintaining a workable rate design for large customers with seasonal or intermittent loads, like many of our agricultural customers.

DEC is also requesting to modify the Determination of Billing Demand provisions for Schedules LGS and I to increase the minimum billing demand from 50 percent to 70 percent of the maximum demand from the previous 12 billing months. In concert, DEC is requesting to eliminate the Minimum Bill provision for these rate schedules. This change would align the related provisions for DEC and DEP. DEC is not proposing changes to the minimum billing demand provisions for Schedule SGS considering the proposed redesign of that rate and in the interest of small customers with seasonal or intermittent loads like many of our agricultural customers.

Lastly, DEC is requesting to increase the ramp-up period for the minimum billing demand provision based on contract demand from three months to 12 months. This change would affect Schedules SGS, LGS, I and OPT, and align the related provisions across DEC and DEP. This change provides an appropriate duration and flexibility for new and expanding

customers to reach their targeted load levels while maintaining the intent and effect of the minimum billing demand provision.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO STANDBY SERVICE REQUIREMENTS.

A. With the proposed demand and TOU window restructuring, DEC recommends eliminating the standby charge for generation with planning capacity factors below 60 percent if customers are served on a TOU-demand rate schedule. Schedule PG has been modified to reflect this proposed change.

Q. WHY IS DEC PROPOSING TO ELIMINATE THE STANDBY CHARGE FOR PLANNING CAPACITY FACTORS BELOW 60 PERCENT FOR CUSTOMERS ON TOU-DEMAND RATES?

A. The proposed three-part demand structure in Schedule OPT would improve price transparency and better align with cost causation based on both the size and timing of customer demands. This new structure recovers fixed costs for system utilization with intermittent resources and eliminates the need for the standby charge for customers on a TOU-demand rate schedule with planning capacity factors below 60 percent.

Q. PLEASE DESCRIBE THE CHANGE AFFECTING INDUSTRIAL RATE CLASSIFICATION.

A. DEC is proposing edits to Schedules I, OPT and MP and to the Service Regulations to specify that the North American Industry Classification System ("NAICS") shall be used for industry classification, including rate eligibility and rider rate classification. With implementation of the Customer Connect

billing system in April 2021, DEC transitioned from using Standard Industrial Classification ("SIC") codes to using NAICS codes. NAICS was developed to replace SIC and is the official classification system used by the United States government.

Q. ARE THERE ANY NOTABLE CHANGES OR CUSTOMER IMPACTS FROM THE TRANSITION FROM SIC TO NAICS?

A. No.

Q. WHY IS DEC PROPOSING TO CLOSE SCHEDULE PG TO NEW PARTICIPANTS?

A. Parallel Generation Schedule PG is a general service TOU-demand rate schedule for customers operating generation systems in parallel with DEC. There are currently six customers served under Schedule PG, and there have been no new participants since 2015. DEC is requesting to close Schedule PG to new participants as an alternative to redesigning the rate with new TOU periods and demand charge structure consistent with proposed changes for DEC's other TOU-demand schedules. Closing Schedule PG to new participants is reasonable given the limited interest in the schedule and given the availability of alternative tariffs providing for parallel generation including Schedule HP and Rider NSC. In particular, DEC believes the redesigned Schedule HP is a more flexible and modernized rate design for new parallel generation customers.

Q. IS DEC PROPOSING ANY CHANGES TO THE RATES UNDER SCHEDULE PG?

A. In addition to the proposed BCC for Schedule PG, DEC is proposing rate increases for the energy and demand charges under Schedule PG, at an equal percentage, in order to recover the revenue increase based on the cost of service study. DEC also proposes to increase the standby charge by the same percentage as the overall revenue increase, from $1.8094 to $2.00. This increase is justified by the unit cost study. The proposed standby charge rate would continue to apply to standby service provisions in Schedule HP.

F. Outdoor Lighting Service

Q. PLEASE DESCRIBE HOW RATES ARE ADJUSTED FOR THE OUTDOOR LIGHTING RATE SCHEDULES.

A. DEC provides outdoor lighting service under Outdoor Lighting Service Schedule OL, Street and Public Lighting Service Schedule PL, and Nonstandard Lighting Service (Pilot) Schedule NL. Rates under Schedule OL and Schedule PL fall into three categories: Existing Pole, New Pole, and New Pole Underground. Rates for the latter two categories are based on the corresponding Existing Pole rate, plus a fixed adder. Overall, DEC proposes to increase all Existing Pole rates by a consistent percentage to achieve the proposed revenue increase, by rate schedule. There are a small number of exceptions where rate increases for certain lighting fixtures are adjusted to maintain or improve alignment in pricing for the same fixture on Schedules OL and PL. The rates for New Pole and New Pole Underground are increased by

the same dollars per month as their corresponding Existing Pole rates, before applying the applicable adder fees.

DEC proposes to increase the new pole adder fee that applies to both the New Pole and New Pole Underground rates on Schedules OL and PL from $6.63 per month to $7.77 per month. The proposed rate of $7.77 per month was derived by applying the Extra Facilities rate of one percent per month to DEC's current total cost to install a new standard 30-foot wooden pole.

Q. IS DEC PROPOSING ANY CHANGES TO OUTDOOR LIGHTING RATES FOR GREENWOOD CUSTOMERS?

A. Yes. DEC is proposing price updates for the two LED fixtures on Greenwood Outdoor Lighting Schedule SL to maintain alignment with corresponding fixtures on Schedule OL. DEC is not proposing any changes to Incandescent and Mercury Vapor fixtures on Schedule SL.

Q. IS DEC PROPOSING ANY CHANGES TO THE FEES IN ITS LIGHTING SCHEDULES?

A. DEC is not proposing any changes to the fees in its outdoor lighting rate schedules except for the new pole adder fee discussed above.

Q. WHAT OTHER CHANGES ARE BEING PROPOSED TO DEC'S OUTDOOR LIGHTING SERVICE?

A. DEC is proposing to establish a new tariff for Outdoor Lighting Service Regulations and to increase the minimum contract term for lighting fixtures on distribution poles from three years to five years.

Q. WHY IS DEC REQUESTING TO ESTABLISH A NEW TARIFF FOR OUTDOOR LIGHTING SERVICE REGULATIONS, AND HOW WOULD IT BE IMPLEMENTED?

A. DEC has received feedback from stakeholders that establishing a tariff for Outdoor Lighting Service Regulations ("OLSR") would provide clarity in DEC's policies related to outdoor lighting and beneficial alignment with DEP. The template for the proposed OLSR was based on the corresponding tariff in DEP. The primary intent of the OLSR is to consolidate and clarify DEC's common policies related to outdoor lighting; it is not intended to change DEC's current policies except as noted in my testimony. Policies specified in the OLSR are no longer required to be included in the tariffs for Schedules OL and PL, and as such have been deleted, resulting in rate schedule tariffs that are much more concise and easier to understand.

Q. WHY IS DEC REQUESTING TO INCREASE THE MINIMUM CONTRACT TERM FOR ITS LIGHTING SCHEDULES?

A. DEC is experiencing attrition on its outdoor lighting rate schedules. Lighting assets have long useful lives, typically averaging 32 years. A three-year contract term is not adequate to ensure that customers retain the assets long enough so that DEC can recover its costs. A minimum five-year term will better attract customers who want lighting service long-term and will allow DEC to recover more of its costs to serve those customers and minimize attrition.

G. Service Riders

Q. WHAT CHANGES ARE REQUESTED TO DEC'S SERVICE RIDERS?

A. Service riders are offered to modify standard service under DEC's rate schedules to better reflect the cost of meeting unique or special customer requirements. DEC is proposing pricing updates for Manually Read Meter Rider MRM; to terminate its Transmission Discount Rider TD; to modify the availability criteria for its Economic Development Rider EC and Economic Redevelopment Rider ER; and to modify availability of its Unmetered Service Rider US.

Q. WHAT CHANGES IS DEC PROPOSING TO ITS MANUALLY READ METER RIDER?

A. DEC is proposing price changes for the initial set-up fee and monthly rate associated with Rider MRM to better reflect current cost estimates. DEC performed a meter services study to estimate costs based on five-year cash flows. The estimated initial set-up fee is $186.95, and the estimated monthly rate is $16.52. DEC is proposing an initial set-up fee of $190.00, which matches the rounded estimated cost, and a monthly rate of $15.00, which moves pricing closer to estimated cost. DEC limited the price increase for the monthly rate to approximately 25 percent to employ gradualism for existing participants. The price updates associated with Rider MRM are included in the miscellaneous revenue adjustment proforma discussed in Section II above.

Q. WHY IS DEC REQUESTING TO TERMINATE TRANSMISSION DISCOUNT RIDER TD?

A. Rider TD has not been available or in effect since the initial two-year pilot period ending in 2014. DEC is requesting for formally close the rider to provide clarity on available customer options.

Q. WHAT CHANGES IS DEC PROPOSING TO THE ECONOMIC DEVELOPMENT AND REDEVELOPMENT RIDERS?

A. DEC is modifying the availability criteria of Riders EC and ER to reflect recently enacted S.C. Act No. 220 of 2022 ("Act 220"), specifically, certain employment, size and capital investment criteria necessary to satisfy the definition of "Qualifying customer" in Act 220.

Q. WHAT CHANGES IS DEC PROPOSING TO UNMETERED SERVICE RIDER US?

A. DEC is proposing to modify language in Rider US to expand the applicability of the rider to distribution poles that are not used for outdoor lighting. This change aligns related riders in DEC and DEP.

H. Other Riders

Q. WHAT CHANGES ARE BEING PROPOSED TO THE EDIT-1 RIDER?

A. DEC is proposing to update the EDIT-1 Rider to account for the accelerated return of excess deferred income taxes as described in Witness Jiggetts' testimony and as indicated in Beveridge Exhibit 4. The derivation of the EDIT-1 Rider is in Beveridge Exhibit 7.

I. Pricing Conventions

Q. IS DEC PROPOSING ANY GENERAL CHANGES TO PRICING CONVENTIONS?

A. Yes. DEC's proposed prices for demand charges across all tariffs have been rounded to two decimal places (one cent) as compared to the current prices which are rounded to four decimal places (one hundredth of a cent). This change is primarily intended to align the pricing conventions of DEC and DEP. This simplification will not hinder DEC's ability to set prices accurately.

IV. PROGRAMS

Q. IS DEC PROPOSING ANY CHANGES TO EXISTING PROGRAMS?

A. Yes. DEC is proposing minor updates to the Remote Meter Reading and Usage Data Service ("RMRUDS") program.

Q. WHAT CHANGES ARE PROPOSED FOR REMOTE METER READING AND USAGE DATA SERVICE?

A. DEC is proposing to remove option B.1. Monthly Data; to add a description to option B.2. Next Business Day Data; to change the standard minimum contract term; and to make minor updates to existing language for clarification. DEC is proposing to remove option B.1., because interval data is now retrieved daily instead of monthly as standard service for all customers with Smart Meters, following completion of AMI deployment. DEC is proposing to add a description to option B.2. (revised to B.1.) to describe the current program available for Next Business Day Data: Energy Profiler Online. This change is intended to clarify that the Next Business Day Data option under RMRUDS is

comparable to the Energy Profiler Online option in DEP's Meter-Related Optional Programs Rider MROP. DEC is also proposing to reduce the minimum contract term from three years to one year, because new customers are most likely to have Smart Meters and not require additional facilities.

V. REGULATIONS AND POLICIES

Q. ARE THE RATES CONTAINED WITHIN THE SERVICE REGULATIONS BEING UPDATED?

A. Yes. DEC is seeking to reduce fees in its Service Regulations resulting from AMI efficiencies. DEC is proposing to lower service connection and reconnection charges from $15.00 to $8.00. DEC is also proposing to lower the returned payment fee from $20.00 to $5.00 to reflect actual costs to process returned checks and to align with DEP. Language has been added to the Service Regulations to describe the returned payment fee and price, which were previously not specified in DEC's tariffs.

Q. ARE THERE OTHER CHANGES BEING MADE TO THE SERVICE REGULATIONS?

A. Yes. In addition to minor edits for clarification, DEC is proposing to increase the minimum contract term for Extra Facilities from five to 10 years and to close the monthly charge for a separate transformer to new customers.

Q. WHY IS DEC REQUESTING TO INCREASE THE MINIMUM CONTRACT TERM FOR EXTRA FACILITIES?

A. The current monthly rate of one percent for Extra Facilities requires 100 months, in nominal dollars, to fully recover initial capital investment. DEC is proposing to increase the minimum contract term for Extra Facilities from five

years to 10 years to better reflect the expected time required to recover the full investment.

Q. WHY IS DEC PROPOSING TO CLOSE THE MONTHLY CHARGE FOR A SEPARATE TRANSFORMER?

A. Section 17.a. of the approved Service Regulations allows DEC to provide a separate transformer for the exclusive use of one customer where service to certain types of equipment may create voltage disturbances on DEC's system. In these cases, DEC is allowed to bill the customer 30 cents per kVA per month for the separate transformer. However, for many years, DEC has consistently utilized the Extra Facilities provision to recover such investments necessary to protect DEC's system instead, as allowed under Section 17.d. The Extra Facilities provision provides more flexibility and ensures that customers are charged appropriately for the specific investment(s) required. As such, DEC is proposing to close the legacy monthly charge of 30 cents per kVA for a separate transformer. Existing customers may continue to receive service under this rate, but new customers requiring equipment protection investment would be charged under Extra Facilities.

Q. WHAT CHANGES ARE PROPOSED TO THE LINE EXTENSION PLAN?

A. DEC is proposing to modify the Line Extension Plan to more clearly distinguish between permanent and temporary service and to define the relevant terms for temporary service. For that purpose, DEC has added three definitions (for "permanent service," "nonpermanent manufactured home," and "temporary

service") and a clarification regarding construction cost for temporary service. DEC has also added two new sections: "extensions for new installations receiving temporary service" and "changes to the service involving upgrades, relocations or removal of service," which restates existing policy from the Service Regulations. Overall these changes provide clarity and better alignment with the Line Extension Plans for DEP.

VI. IMPLEMENTATION

Q. HOW DOES DEC PROPOSE TO IMPLEMENT THE VARIOUS CHANGES REQUESTED IN THIS CASE?

A. DEP will file with the Commission revised tariffs consistent with the rates and charges approved in the Commission's final order in this case. The compliance tariffs shall become effective on the effective date set by the Commission unless otherwise ordered by the Commission.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.